Technical Ability and Economics to Meet Air Emission Requirements using Alternate Fuels for Steam Generation

Alberta Environment

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EXECUTIVE SUMMARY

Currently natural gas is the primary fuel source for generating steam for enhanced oil recovery projects, including Steam Assisted Gravity Drainage (SAGD). The increase in the price of natural gas has led a number of proponents to look at substituting alternate fuel sources. Some of the alternate fuels may require pollution control equipment to meet acceptable levels of pollutant emissions.

The objective of this review was to examine the technical feasibility and economics of implementing pollution control equipment on combustion equipment of the scale typically used to generate steam for SAGD operations. Uncontrolled emissions for the alternative fuels in a single 200 MMBtu/hr steam generator would be as high as 26.8 tonnes/d of SO_x and 21.4 tonnes/d of particulate.

Proven technologies are commercially available at the appropriate scale to reduce air pollutant emissions for alternate fuels in SAGD operations, including:

- wet or dry flue gas desulphurisation for SO_x control,
- low NO_x burners and selective catalytic reduction for NO_x control, and
- electrostatic precipitators and baghouses for particulate control.

Firing synthesis gas produced by gasification of a waste fuel, such as coke, is another option that can meet emission targets.

Emissions control will significantly increase the cost of several of the alternate fuels, primarily due to their high sulphur content. For the highest sulphur fuel in this study, SO_x control would add at least $3.00/GJ to the effective cost of the fuel. Greenhouse gas emissions would also increase, with fuel related CO_2 emissions from 1.4 to 2.6 times those of natural gas.

A more detailed engineering study is recommended to determine more accurate capital and operating cost impacts for the alternative fuels. This study should also examine cost and other issues around both the firing of solid fuels in this scale of equipment and the disposal of the significant amount of wastes generated from the pollution control equipment.

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TECHNICAL ABILITY AND ECONOMICS TO MEET AIR EMISSION REQUIREMENTS USING ALTERNATE FUELS FOR STEAM GENERATION

1.0 BACKGROUND

Currently natural gas is the primary fuel source for generating steam for enhanced oil recovery projects, including Steam Assisted Gravity Drainage (SAGD). The increase in the price of natural gas has led a number of proponents to look at substituting different types of fuel sources (typically liquid fuels such as diesel or heavy fuel oil or solid fuels such as petroleum coke, coal, or bitumen) for the natural gas. At the moment within Alberta, there are no specific air emission guidelines for these types of situations.

The fuels being considered as alternatives to natural gas typically have different levels of sulphur, fuel bound nitrogen compounds, and particulate that may be emitted into the atmosphere. Depending on the size of the project, total air contaminant emissions can be substantive and well above other levels emitted by other point sources that are subject to emission guidelines.

In terms of consistency with other industrial sectors, oilsands, oil and gas, and electrical utilities all have either sulphur recovery or sulphur dioxide removal requirements, NOx emission controls, and particulate controls as is appropriate. Also, the pollution control equipment and processes are similar with volume of the effluent stream being the main variable.

2.0 SCOPE

The objective of this study was to supply expert advice on both the technical feasibility of controlling emissions of SO_x, NO_x, and particulate matter from small scale steam generation units (including pollution control equipment most likely to be utilized) along with an economic analysis of these pollution control options. The economic analysis would include both an analysis on the cost to control emissions on a $/tonne basis and also on the basis of when a steam generator using a solid or liquid fuel would incur the same costs as a natural gas fired steam generator based on the price of natural gas when used as a fuel.

3.0 PARAMETERS OF THE STUDY

This section will detail various parameters of the study including:

- target for PM, NO_x, SO_x, for the fuels to be considered
- elemental analysis and other properties of the fuels to be considered in the study
- potential for other emissions of concern, such as mercury
- size range of equipment
- costs of fuels and range of natural gas price

This data will form the basis for the rest of the study.

3.1 Target Emission Levels

The target emission numbers used in the analysis for PM/NOx/SOx were 10/65/78 ng/Joule of heat input, respectively for the solid or liquid fuel option and the NO_x number for natural gas fuel is 40 g/GJ of heat input for boilers greater than 100 MMBtu/hr and 26 g/GJ for boilers between 10-100 MMBtu/hr. Table 1 summarizes the target emission numbers.

Table 1: Target Emission Levels for Solid and Liquid Fuels based on Higher Heating Value of the Fuel

Pollutant	Solid or Liquid Fuel Target (ng/J of heat input)	Natural Gas Target heat input > 100 MMBtu/hr (ng/J of heat input)	Natural Gas Target heat input 10-100 MMBtu/hr (ng/J of heat input)
SO_x	78		
NO_x	65	40	26
particulate	10		

Carbon monoxide (CO) and mercury are not included in Table 1 but should be considered with each of the alternate fuels. Reducing NO_x levels by combustion controls is often a trade off with higher CO emissions and the level of NO_x reduction achievable with acceptable CO emissions will be a function of the fuels combustion properties. Mercury emissions may be subject to emission controls in the future, with potential mercury emissions primarily determined by the fuel composition.

3.2 Properties of Selected Alternative Fuels

Combustion of fossil fuels results in emissions of CO_2 (a greenhouse gas), SO_x, NO_x and ash particles. CO_2 is produced by combustion of carbon in the fuel. SO_x emissions are largely determined by the sulphur content of the fuel, with essentially all of the sulphur converted to SO_2 during combustion. NO_x emissions are partly a function of nitrogen content of the fuel but are primarily determined by the temperatures, residence time and the ratio of oxygen to fuel in the flame region. Particulate emissions are primarily determined by fuel ash content but can also result from the formation of carbon particles (soot) due to poor or incomplete combustion. Some portion of the ash may collect on heat transfer surfaces in the boiler and some will remain entrained in the flue gas. The percentage of ash exiting with the flue gas will depend on fuel properties, combustion conditions, and boiler design. In addition to these primary pollutants, emissions of trace elements, such as mercury, may also result from combustion of fossil fuels.

Fuel properties can have a significant impact on selection of the best technology for minimal emissions and on the costs of operation of emission control equipment. Fuel properties that may influence technology selection and air pollutant emissions include:

- sulphur content per unit heating value – determines maximum SO_x emissions and design and operating cost of SO_x removal equipment per unit of energy produced
- nitrogen content – nitrogen contained in the fuel partly determines maximum NO_x emissions. The actual NO_x emissions will depend on burner and furnace design.
- ash content and composition – affects design and operation of heat exchanger surfaces and any requirement for particulate removal equipment
- combustion reactivity – affects particulate emissions, unburnt carbon in flyash and the flexibility to reduce NO_x emissions by combustion modifications,
- electrical resistivity of fly ash – determines the effectiveness of electrostatic precipitators for particulate removal,
- trace metals content – trace metals, such as vanadium and mercury, may result in corrosion and/or scaling of heat exchangers and possible air emissions (mercury), and
- carbon content per unit heating value – determines greenhouse gas emissions.

Table 2 lists the alternate fuels considered in this study along with some of their relevant properties. The analysis shown for sub-bituminous coal is a typical analysis for Alberta sub-bituminous coal, however moisture, ash and sulphur content can vary between coal deposits and even between seams within a given coal deposit. Information on trace element content was not readily available for all fuels.

The synthesis gas composition shown in Table 2 is an estimated clean synthesis gas composition expected from gasification of Suncor coke in a ChevronTexaco quench gasifier. This composition represents a synthesis gas with moisture and H_2S and other reduced sulphur compounds removed. A commercial gasifier would include equipment to remove essentially all particulate, H_2S and some or all of the CO_2 in an acid gas separation system, producing a synthesis gas that could be fired in a boiler without the need for particulate or SO_x removal equipment.

Table 2: Properties of Selected Alternative Fuels

Description	Market Natural Gas	Sub-bituminous Coal	Syncrude Coke1	Suncor Coke1	Athabasca Bitumen1,2	Suncor Diesel3	Raw Syn Gas4
Parameter	gas	solid	solid	solid	semi-liquid	liquid	gas
Heating Value							
Gross HV, MJ/kg (HHV)	50.7	22.5	29.30	33.50	41.80	46.46	9.48
Net HV, MJ/kg(LHV)	45.8	21.45	28.94	32.70	39.54	43.76	8.83

Proximate analysis:							
Volatile Matter	-	32					
Fixed Carbon	-	46.4					
Ash	-	9.5	8.63	2.85	0.75	<0.18	
Moisture	-	12.1	0			<0.01	
Ultimate analysis:(%total)							
Carbon	69.4	58.1	77.74	83.93	82.5	87.3	34.4
Hydrogen	22.5	3.52	1.69	3.70	10.5	12.5	3.0
Oxygen	0	15.8	0	0.00	1.2		61.4
Nitrogen	8.1[5]	0.91	4.61	3.34	0.45	13.0 mg/kg	1.2
Sulfur	trace	0.67	7.76	5.78	5.1	0.04	0
Chlorine	0	6.5 ppm				<1 ppm	
Trace Elements (mg/kg)							
Hg					<0.005		
Se					0.59		
As		4.4			0.68	<0.3	
Cd		0.6					
Pb		22.4			3.2		
Sb					0.093		
Fe					530	<0.15	
Cr		2			2.96		
Na					39.3	<1.5	
Ni		6		455	74	<0.15	
V		6		1010	260	<0.05	

[1] coke and bitumen typical analysis from AOSTRA Handbook

[2] trace element composition of bitumen from Hosterman et al., 1990

[3] Suncor diesel analysis from Alberta Environment

[4] synthesis gas composition for ChevronTexaco gasifier operating on petroleum coke with H_2S recovery, estimated composition of 34% H_2, 42% CO, 22% CO_2, 2% N_2 by volume.

[5] nitrogen present in natural gas as N_2, not as fuel bound nitrogen

4.0 POTENTIAL POLLUTANT EMISSIONS

Using the fuel's heating value and elemental composition, maximum emissions of SO_x and particulate were estimated and compared to the emission targets. Under good combustion conditions, essentially all of the sulphur in the fuel will be converted to SO_2 and will exit with the furnace exhaust. Estimating particulate emissions based on fuel composition will give an upper limit to possible particulate

emissions. Depending on the amount and composition of ash, some of the particulate may collect on heat transfer surfaces or settle out in the furnace or stack system. NO_x emissions cannot be estimated based on fuel composition as a significant portion of the nitrogen in the fuel may be converted to N_2 rather than NO_x and a significant amount of NO_x may form in the flame by reaction of oxygen and nitrogen in the combustion air.

Table 3 summarizes the estimated maximum emissions of SO_x and particulate in kg/GJ of thermal input for the various fuels, assuming no emission control equipment, along with the percentage removal required to meet the emission targets listed in Table 1. The required removal of SO_x ranged from 86.9% for sub-bituminous coal to 98.5% for Syncrude coke. The required removal of particulate ranged from 74% for Suncor diesel to 99.8% for sub-bituminous coal.

Natural gas, Suncor diesel, and synthesis gas could be fired without the need for SO_x removal from the flue gas. Synthesis gas has associated SO_2 emissions that occur at the gasifier site. These emissions will depend on the design and operation of the sulphur recovery unit included with the gasifier system. Similarly, natural gas has associated SO_2 emissions at the gas processing plant where H_2S is removed and converted to sulphur.

Table 3: SOx and Particulate Emissions with no Emission Control Equipment (based on fuel HHV)

Description	Market Natural Gas	Sub-bituminous Coal	Syncrude Coke	Suncor Coke	Athabasca Bitumen	Suncor Diesel	Raw Syn Gas[1]
SO_x (ng/J)	n/a	596	5297	3451	2440	17.2	n/a
SO_2 removal to meet 78 ng/J	0	86.9	98.5%	97.7%	96.8%	0%	
particulate (ng/J)	n/a	4222	2945	851	179	38.7	n/a
particulate removal needed to meet 10 ng/J	0	99.8%	99.7%	98.8%	94.4%	74.2%	0

[1] Gasification followed by conventional acid gas sweetening can achieve sulphur and particulate levels similar to natural gas. There will be SO_2 emissions from the sulphur recovery unit tail gas incinerator.

Table 4 gives the emissions of SO_x and particulates with no emission control equipment for each fuel assuming a typical SAGD steam generating unit with a thermal input of 200 MMBtu/hr (211 GJ/hr). The uncontrolled emissions of SO_2 range from 126 kg/h (3 tonnes/d) for sub-bituminous coal to up to 1116 kg/hr (26.8 tonnes/d) for Syncrude coke. These SO_2 emissions are 8 to 68 times the emissions

target level of 8.22 kg/h (0.2 tonnes/d). The uncontrolled emissions of particulates range from 8.2 kg/h for Suncor diesel to 890 kg/h for sub-bituminous coal. These particulate emissions are 4 to 420 times the emission target level of 2.1 kg/h.

Table 4: Mass Emissions of SOx and Particulate with no Emission Control Equipment (thermal input of 200 MMBtu/hr based on fuel HHV)

Description	Emissions Target	Subbituminous Sub-bit Coal	Syncrude Coke	Suncor Coke	Athabasca Bitumen	Suncor Diesel
fuel rate (kg/hr)		9370	7190	6290	5040	4540
SO_x (kg/h)	**16.44**	**126**	**1116**	**727**	**514**	**3.6**
SO_x (tonnes/d)	0.4	3.0	26.8	17.4	12.4	0.08
particulate (kg/h)	**2.10**	**890**	**620**	**180**	**38**	**8.2**
particulate (tonnes/d)	0.05	21.4	14.9	4.3	0.91	0.2

In order to meet the targets for SO_x and particulate emissions without the need for emission control equipment, a fuel must contain less than 39 ng/J of sulphur and 10 ng/J of ash. For a liquid fuel with the same heating value as diesel (44 MJ/kg LHV) this equates to less than 0.17% by weight sulphur and less than 0.044% by weight ash. The Suncor diesel meets this requirement for sulphur. Most Alberta sub-bituminous coals would exceed 78 ng/J of SO_2 (0.08% by weight sulfur) and would require SO_x reduction.

5.0 COMMERCIALLY AVAILABLE TECHNOLOGIES FOR REDUCING EMISSIONS

Technologies are commercially available to reduce emissions of SO_x, NO_x and particulates from fossil fuel combustion. These technologies have been applied both at a large scale in central power plants and also at a small scale in waste incinerators and industrial boilers. Table 5 lists some of the major manufacturers in North America of systems for control of SO_x, NO_x and particulates. Some of these manufacturers offer standard packaged emission control equipment in a size range appropriate for SAGD. The following sections discuss these technologies and the levels of emissions that are achievable in a plant with 200 MMBtu/hr of thermal input.

Table 5: Examples of Manufacturers of Emission Control Equipment with Size Appropriate for SAGD Installations

Manufacturers	Contact Info	Example Equipment Offered
ALSTOM	Tel.: +1-450-746-6500 www.power.alstom.com	• Fabric filters (FF) • Flue gas desulfurization (FGD) • Electrostatic precipitator (ESP) • Scrubbing systems
Cansolv Technologies Inc	Paul Parisi Vice-President, Engineering Tel.: +1-514-382-4411 ext.25 www.cansolv.com	• CANSOLV® SO2 Scrubbing System
Mikropul	Mikropul Canada Tel.: 905-712-0722 www.mikropul.com	• particulate removal with baghouses, wet scrubbers, wet electrostatic precipitators
Ducon	TEL: (631) 694-1700 www.ducon.com	• SCR NOx, CO & VOC Catalytic Systems • Baghouse Filter • Dry Flue Gas Desulfurization • wet scrubber systems • Wet & Dry Electrostatic Precipitators • Activated Carbon Filter
Andersen 2000 Inc	Phone: 770-486-2000 www.crownandersen.com/Andersen.html	• SO_2 Scrubbers • Particulate Scrubbers
Von Roll	Telephone +1 770 613 97 88 www.vonrollinc.com	• SCR systems • wet SO_2 scrubber • semi-dry SO_2 scrubber
CSM Worldwide, Inc.	Tel. 908-233-2882 www.csmworldwide.com	• SCR systems
Wheelabrator Air Pollution Control Inc.	Wheelabrator Canada Co. Telephone: 905-875-1662 www.wapc.com	• wet SO_2 scrubbers • spray dry SO_2 scrubbers • dry SO_2 scrubbers • SCR NO_x reduction • baghouses • ESP's

5.1 SO_2 Reduction with Flue Gas Desulphurization

SO_2 can be removed from the gaseous combustion products by reaction with compounds such as lime (CaO) and sodium hydroxide (NaOH). The predominate technology used to achieve high levels of SO_2 removal (<95%) is a wet scrubber. The flue gas is typically cooled and passed through a vessel to contact the gas with a slurry of water and sorbent. The SO_2 reacts with the sorbent to form sulphide and/or sulphate compounds. Scrubbers require makeup water, consume sorbent and generate a waste product for disposal (or for use as a by-product), proportional to the amount of SO_2 removed from the flue gas. Depending on design and operation, scrubbers may also partially remove other pollutants such as particulates and trace metals.

Modern flue gas desulphurization (FGD) systems have demonstrated SO_2 emission levels down to 43 to 86 ng/J in large coal-fired utility boilers. Costs for these large FGD systems have dropped dramatically since their introduction. Operating costs will depend on sorbent cost and consumption and the cost of disposal of spent sorbent. Reported operating costs for wet scrubbers used in the coal-fired utility industry were US$300 to US$630/ton of SO_2 removed (Chambers, 2001). Wet FGD units consume a significant amount of electricity to circulate scrubber solution and to overcome flue gas pressure drop through the scrubber.

A detailed comparison of the costs and benefits of various scrubber designs was outside the scope of this project. Several vendors were contacted in order to estimate availability, capital cost and operating requirements for a scrubber suitable for 100 to 200 MMBtu/hr boilers fired with Athabasca bitumen and able to achieve >95% removal of SO_2 from the flue gas. Andersen 2000 Inc. (www.crownandersen.com) responded with a preliminary design and cost estimate for a boiler sized to produce 100 MMBtu/hr of steam. This design and cost estimate was used to estimate capital cost, chemical consumption, and waste generation of a 100 MMBtu/hr boiler fired with Athabasca bitumen. Several other companies supply alternative scrubber solutions and there is no intent to endorse the Andersen 2000 design by this discussion.

Figure 1 is a schematic of the package scrubber system proposed by Andersen 2000 Inc. Major components are:

- spray quench section
- horizontal spray-baffle scrubber
- mist eliminator
- induced draft fan
- scrubbing solution recirculation tank
- scrubbing solution pump
- exhaust stack.

Table 6 summarizes the capital costs and consumables for this scrubber system based on information supplied by Andersen 2000 Inc. The information in Table 6 has been scaled to a 200 MMBtu/hr thermal boiler (a typical size for SAGD) fired with Athabasca bitumen and sufficient SO_2 capture to meet SO_2 emissions of 78 ng/J.

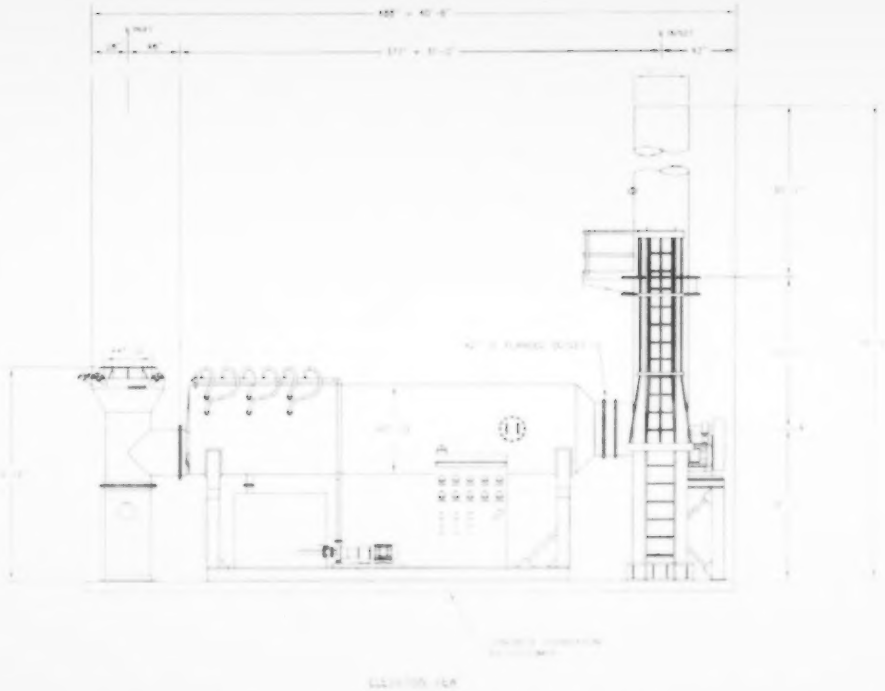

Figure 1: Example Wet Scrubber for SO2 Removal (Andersen 2000 Model HS100)

Table 6: Summary of Costs for Example Scrubber System for 200 MMBtu/hr Thermal Unit fired with Athabasca Bitumen

Item	Estimate (Andersen 2000 Inc. HS-100 Unit)
capital cost	US$ 361,000
SO_2 removal efficiency	95 to 98%
sorbent	caustic soda (NaOH) in 50% by weight water slurry
make up water consumption	8.3 m^3/hr
liquid waste discharge	4.8 m^3/hr at pH 6.9
chemical consumption	1.07 kg NaOH/kg of SO_2 removed
SO_2 removal	498 kg/hr
SO_2 emissions	16.5 kg/hr (78 ng/J)
electric power consumption	82 kW/hr

Assuming an electricity rate of $0.07/kWhr, a capital life of 10 years, cost of capital of 15%, utilization factor of 90%, and cost of NaOH of $0.40/kg the cost of SO_2 removal with a wet scrubber using NaOH is about $470/tonne of SO_2 removed. This cost does not include operating manpower, equipment maintenance or waste disposal costs. In this design, over 90% of the cost of SO_2 removal is the NaOH chemical cost. This estimated cost per tonne falls within the previously mentioned range of US$300 to 630/ton of SO_2 removed.

5.2 NO_x Reduction:

In most combustion processes, essentially all of the NO_x produced is in the form of NO. NO_2 may also be produced in fluidized bed combustion, which operates at lower combustion temperatures.

Combustion produces NO_x by the following two routes:

- thermal NO_x – formed by reaction of O_2 and N_2 at high temperatures, and
- fuel NO_x – formed by the oxidation of organic nitrogen containing species in the fuel.

The relative contribution of thermal NO_x and fuel NO_x is dependent on both fuel properties and combustion conditions, including residence time in the flame, temperature, and oxygen availability. In an uncontrolled coal flame as much as 80% of the NO_x results from fuel NO_x in contrast to a natural gas flame where 100% is thermal NO_x.

With current technologies NO_x emissions are reduced by:

- modifying combustion flame conditions in order to reduce NO_x formation (staged low NO_x burners, exhaust gas recirculation),
- injecting hydrocarbons to reduce NO_x to N_2 near the flame zone (reburning), and
- treating the flue gas to convert NO_x to N_2 using SNCR or SCR reactors.

5.2.1 Low NO_x Burners

Modifying the combustion zone conditions is the most cost effective method for reducing NO_x emissions. Low NO_x burners incorporate some or all of the following techniques:

- reduce oxygen concentrations by minimizing excess air,
- reduce maximum flame temperatures by reducing intensity of mixing,
- inject fuel into an initial 'fuel-rich' zone to promote conversion of fuel nitrogen to N_2 instead of NO_x,
- secondary oxygen rich zone to fully burn the remaining hydrocarbons and CO, and
- sometimes a second fuel rich zone is created (reburning) followed by a third oxygen rich zone.

The techniques used to reduce NO_x also reduce the intensity of the flame and can result in an unacceptable increase in products of incomplete combustion (carbon in flyash, soot, and/or carbon monoxide). Low NO_x burners can also result in a reducing atmosphere next to heat exchange surfaces that can increase metal corrosion rates and ash slagging problems. Extensive research and full scale testing has gone into the development of modern low NO_x burners for coal and natural gas. Less work has been done with bitumen and heavy crudes. With these fuels, SCR units will likely be required to meet 65 ng/J levels.

Including the cost of capital, low NO_x burners for large coal-fired power plants range in cost from US$250 to US$500/ton of NO_x removed (Soud and Fukasawa, 1996).

5.2.2 Selective Non-Catalytic Reduction (SNCR)

Ammonia compounds when injected into combustion products from 900 to 1100°C will react with NO_x to form N_2. Reagents used in commercial SNCR systems include anhydrous ammonia, urea, and aqueous ammonia. As the temperature window of reaction is narrow, the amount of injection has to be varied with boiler load to prevent excessive slip of unreacted ammonia reagent (ammonia slip) yet maintain sufficient NO_x reduction.

SNCR is relatively inexpensive to install but does not offer NO_x removal levels better than modern low NO_x burners. The system also has the potential for ammonia slip in the flue gas.

5.2.3 Selective Catalytic Reduction (SCR)

SCR technology has been used commercially in Japan since 1980, in Germany since 1986 and in the U.S. since the 90's. SCR systems are relatively complex and increase operating costs due to ammonia consumption and the need to replace catalysts.

Ammonia is injected into the flue gas ahead of the SCR catalyst. The SCR catalyst promotes the reduction of NO_x by ammonia to produce N_2. Optimum temperatures for the reaction are 300 to 400°C. SCR units have been installed primarily in high dust locations before the electrostatic precipitator (ESP) or baghouse. Accurate control systems are required to maximize NO_x reduction while minimizing ammonia slip.

SCR systems are the most expensive NO_x control strategy and are usually combined with low NO_x burner systems to minimize catalyst and ammonia injection costs. Factors affecting cost are NO_x reduction required, catalyst performance and lifetime, system configuration and boiler conditions.

The NO_x reduction achievable with SCR systems is balanced by cost of catalyst and allowable ammonia slip. Commercial installations of SCR systems have achieved NO_x outputs levels of 21.5 to 86 ng/J

with operating costs ranging from US$913 to US$3,780/ton of NO_x removed (Soud and Fukasawa, 1996).

5.3 Particulate Reduction

Particulates in the products of combustion are primarily entrained ash components with a small amount of unburnt carbon. For the scale of combustion systems of 200 MM Btu/hr, particulate can be removed with electrostatic precipitators, baghouse filters, or liquid scrubbers. The removal efficiency of these devices decreases with decreasing particle size. Particles that pass through these devices are primarily smaller than 10 microns (PM 10) with about 50% smaller than 2.5 microns (PM 2.5).

Most of the trace metals in a fuel such as coal will be removed with the ash particles. Volatile metals, such as mercury and selenium, can remain in the vapour phase and pass through particulate removal equipment.

5.3.1 Electrostatic Precipitators (ESP)

As flue gas passes through the ESP, ash particles are charged in the field and attracted to the grounded collector plates. The deposited flyash is removed by occasional rapping of the collector plates followed by collecting the ash in hoppers below the plates. Surface area, ash loading, particle size, flyash composition, and resistivity of the fly ash influence ESP performance. ESP's work best with a fly ash resistivity between 10^7 and 10^{11} ohm-cm.

Electrostatic precipitators have been widely used in the coal-fired power generation industry. Dry ESP's typically remove >95% of the ash particulate from the flue gas. Fine particulates (PM2.5) are difficult to remove with dry ESP's partly due to re-entrainment during rapping of the plates for ash removal.

Wet electrostatic precipitators are currently used in the treatment of waste incineration flue gas. Rather than rap the plates for ash removal, a mist or film of water continually flows down the plates to remove the ash without re-entrainment. Recent designs cool the ESP plates to condense a thin film of water from the flue gas. This reduces fresh water needs and more evenly wets the plates. Wet electrostatic precipitators are capable of removing fine particulates (PM2.5) with up to 99.9+% efficiency. Manufacturers claim dust removal to 2 microns/m^3 and zero percent opacity (www.mikropul.com , www.cgscgs.com).

5.3.2 Baghouses

Baghouses are used as an alternate to or occasionally in combination with ESP's for particulate removal. They are large enclosures containing numerous porous fabric filter bags. Ash builds up as a dry cake on the dirty side of the bag. This cake improves fine particle removal and can help to remove other pollutants such as trace metals, chlorine, and SO_2. With a build-up of cake the pressure drop across the filter increases. Filter cake is removed periodically by rapping or by injecting a pulse of backflow air. Filter cake drops to hopper at the base of the baghouse.

Baghouses are a proven technology. They are more effective than ESP's for removing ash particles smaller than 10 microns and their performance is not affected by composition or changes in ash resistivity. Maintenance costs can be significant, as filter bags have to be replaced periodically.

MikroPul Canada Inc. recommended their model 459J fabric filter for a 200 MMBtu/hr installation with an outlet particulate specification of 25 mg/Nm^3 (equivalent to about 6.9 ng/J). This unit is about 5.54 m long x 3.66 m wide x 12.1 m tall with an approximate price of $110,000 Canadian (approximately $3.00/SCFM). This estimated price is for the basic baghouse and does not include ancillary equipment such as screw conveyors, discharge valves, exhaust fans, control panels, etc.

5.4 Synthesis Gas from Gasification of Fossil Fuels

Gasification systems can be used to produce a medium BTU synthesis gas from a variety of fossil fuels as a substitute to natural gas for production of steam. In a gasification or partial oxidation process, the fossil fuel is reacted with oxygen at high temperature producing a gas containing primarily CO, H_2, CO_2, H_2S and N_2. After passing through a water scrubber to remove particulate and water soluble by-products, the gas is treated by chemical or physical absorption processes to remove CO_2 and H_2S. The resulting synthesis gas will have H_2S and particulate concentrations similar to sales grade natural gas and can be used to generate steam, can be fired in gas turbines to generate electricity or used as a feed for petrochemicals production. The ChevronTexaco entrained flow gasifier is an example of a commercial gasifier installed in over 60 locations to convert coal, petroleum coke or heavy crude to synthesis gas (a combination of CO, H_2 and CO_2) for use either in gas turbines for power generation or for production of chemicals such as ammonia. More information on gasification can be found at www.gasification.org.

Entrained flow, oxygen blown gasifiers, such as ChevronTexaco or Shell technology, combined with conventional systems for removal of particulate and reduced sulphur compounds from the synthesis gas, can produce a synthesis gas clean enough to meet the Table 1 target emission levels for SO_x and particulate. The synthesis gas would not contain fuel bound nitrogen and NO_x emissions at the point of end use would be similar to those achieved with natural gas. SO_2 emissions may still be produced at the gasifier depending on the design of the sulphur recovery unit. Sulphur recovery >98% can be achieved with modern sulphur recovery systems. A further advantage is the reduced waste disposal requirement by converting H_2S to elemental sulphur rather than SO_2 to sulphate wastes.

Gasifiers and the related oxygen plant are complex and benefit from economies of scale. For the application in SAGD, a centrally located gasifier with a synthesis gas distribution system supplying the SAGD fields would be the likely scenario. An integrated design could also produce electricity, steam and hydrogen for use in bitumen upgrading.

5.5 Mercury Control

Mercury exists in trace amounts in coal and other fossil fuels. Mercury is emitted from combustion systems in the vapour phase as both elemental and oxidized mercury and may also be present in the

particulates. Future environmental regulations may put limits on the allowable air emissions of mercury from combustion and gasification systems.

Although the mass emissions of mercury from each individual SAGD steam generator may be small, the accumulated impact of a large number of SAGD operations may be significant. The mercury concentration in pipeline quality natural gas is negligible (<0.2 $\mu g/m^3$, < 5.3 x 10^{-6} ng/J) but fuels such as coal and bitumen contain measurable amounts of mercury.

Technology for mercury removal from natural gas or synthesis gas from gasification systems is commercially available. One system uses activated carbon treated with sulphur compounds to absorb elemental mercury from the gas stream and convert it to relatively inert mercuric sulphide. Technology for removal from combustion systems is used commercially in hazardous waste incineration systems and is under development for large coal-fired power plants. Most of the development of mercury removal equipment for combustion flue gas has focused on injection of activated carbon sorbents upstream of a baghouse. The mercury is captured in a benign form on these sorbents.

A recent publication (Rutkowski et al., 2002) compared the cost for mercury removal from synthesis gas with that from combustion systems. Estimated mercury removal costs were $3,412/lb for synthesis gas treatment as compared to $37,800/lb for flue gas treatment. The higher cost for removal from combustion flue gas is mainly due to high dilution with combustion air resulting in much lower mercury concentrations in flue gas than in synthesis gas.

6.0 IMPACT ON GREENHOUSE GAS EMISSIONS

The primary greenhouse gas produced by combustion systems is CO_2. Assuming that the efficiency of steam generation is the same for all of the fuels in this study, the approximate relative CO_2 generation can be estimated from the fuel composition and heating value. Table 7 summarizes the relative generation of CO_2 for the fuel compositions given in Table 2. These CO_2 emission values do not include the additional greenhouse gas emissions associated with production and transport of the fuels or with the operation of combustion and flue gas cleaning equipment.

Table 7: Relative Greenhouse Gas Emissions

Description	Natural Gas	Subbituminous Sub-bit Coal	Syncrude Coke	Suncor Coke	Athabasca Bitumen	Suncor Diesel	Raw Syn Gas[1]
CO_2 (kg/GJ HHV)	50.2	94.7	97.3	91.9	72.4	68.9	132.8
CO_2 (kg/GJ LHV)	55.6	99.3	98.5	94.1	76.5	73.1	142.72
CO_2 emissions relative to natural gas (HHV)	1.0	1.9	1.94	1.8	1.44	1.37	2.65

[1] synthesis gas CO_2 emission does not credit use of waste heat from the gasifier

CO_2 emissions given in Table 7 for synthesis gas produced from coke are significantly higher than those for direct combustion of coke. This increase is due to energy losses during gasification, with the conversion efficiency of fuel to synthesis gas chemical energy typically about 75%. The other 25% is converted to thermal energy that could displace CO_2 emissions from other fuels if the waste steam/heat is used.

7.0 REVIEW OF ECONOMICS

Switching to an alternate fuel to produce steam for bitumen recovery is one response to the high price of natural gas. Several of the candidate alternate fuels contain significant amounts of sulphur and ash and would likely require pollution control equipment. The capital and operating cost of this equipment will add a significant additional cost, reducing the price advantage over natural gas. Additional costs may include:

- capital cost for the pollution control equipment
- manpower to operate the control equipment
- electricity for scrubber solution pumps, induced draft fans, etc.
- chemical costs for scrubber and/or SCR's
- waste disposal costs, particularly for ash disposal and spent SO_2 scrubbing compounds

Table 8 illustrates the impact on fuel costs of pollutant emission control. This initial analysis used approximate costs from the literature (including capital and operating) based on a $/kg of pollutant removed. Determining actual costs for an installation and operation in the Ft. McMurray area would require a detailed engineering and cost study outside the scope of this project.

Costs may be higher than those used in Table 8 due to additional expense for cold weather operation, transportation of sorbent media and chemicals and disposal of spent scrubbing solution and ash. Also, the combustion equipment required for a solid fuel such as sub-bituminous coal or coke would have a higher capital and operating cost than the equivalent natural gas fired equipment. The data in Table 8 assume the same boiler cost for all fuels.

An approximate cost of synthesis gas produced from pet coke is about US$4/GJ (personnel communication with ChevronTexaco, January, 2004). The actual cost of synthesis gas production will depend on cost and properties of the fuel used, size and location of the plant and extent of integration of the gasification plant with other facilities. Most gasification studies in the literature report costs for IGCC systems that produce primarily electricity using gasification, with costs quoted in $/kWh of electricity with capital costs including all the equipment necessary to generate electricity. Current gasification installations are much larger than 200 MMBtu/hr to take advantage of economies of scale. A central gasifier with distribution of synthesis gas and/or steam to the well sites may be a better option than small gasifiers installed at the field sites.

Using a high sulphur fuel such as Suncor coke or Athabasca bitumen in combustion equipment with SO_2 scrubbers would generate a significant amount of waste solid material from the scrubber. Sodium or calcium based scrubbers typically generate 2 to 3 kg of waste for every kg of SO_2 removed. For a 200 MMBtu/hr SAGD steam generator firing Suncor coke, about 700 kg/hr of SO_2 would have to be removed to meet 78 ng/J limits, resulting in about 1.4 to 2 tonnes per day of dry waste disposal from spent sorbent. A large number of such steam generators may result in a significant waste disposal issue in the Ft. McMurray area.

Table 8: Estimated Impact of Emissions Control Equipment on Relative Fuel Costs

Description	Sub-bituminous Coal	Syncrude Coke	Suncor Coke	Athabasca Bitumen	Suncor Diesel
fuel cost	$40/tonne	$10/tonne	$10/tonne	$29/bbl	$45/bbl
fuel cost ($/GJ HHV)	**1.78**	**0.34**	**0.3**	**4.85**	**6.77**
SO_x					
SO_x removal (kg/GJ)	0.518	5.22	3.37	2.36	0
cost of SO_x control ($/GJ) (assuming $600/tonne of SO_2 removed)	**0.311**	**3.13**	**2.02**	**1.42**	**0**
Particulate					
ash removal (kg/GJ)	4.21	3.13	0.841	0.169	0.029
cost of ash removal ($/GJ) (assuming $30/tonne of ash)	**0.126**	**0.088**	**0.025**	**0.005**	**0.001**
NOx					
cost of NO_x removal ($/GJ) (assuming 300 ppm NO_x and $1500/tonne of NO_x removed)	**0.26**	**0.26**	**0.26**	**0.26**	**0.26**
Fuel Cost with Control ($/GJ)	**2.48**	**3.82**	**2.61**	**6.54**	**7.03**

8.0 CONCLUSIONS AND RECOMMENDATIONS

The technical feasibility and cost implications of emissions control was reviewed for several alternatives to natural gas as a fuel for the generation of steam in SAGD projects in the Ft. McMurray area. The following was concluded:

1. Uncontrolled emissions from a single 200 MMBtu/hr steam generator for the alternative fuels examined would range as high as 26.8 tonnes/d of SO_x and 21.4 tonnes/d of particulate.

2. Equipment is commercially available in the size range applicable to SAGD projects for SO_x, NO_x and particulate control to the emission level targets of this study.

3. Emissions control will significantly increase the cost of several of the alternate fuels, primarily due to their high sulphur content. For the highest sulphur fuel in this study, SO_x control would add at least $3.00/GJ to the effective cost of the fuel.

4. Production of synthesis gas from a waste fuel, such as coke, is an option that can meet the emissions targets. This option would likely require a large gasification plant with a synthesis gas distribution system.

5. Greenhouse gas emissions of CO_2 for the alternative fuels will be 1.4 to 2.6 times those of natural gas.

6. Pollution control equipment to reduce emissions will generate both liquid and solid wastes that will require disposal with an associated cost.

A more detailed engineering study is recommended if more accurate values are required for emission control costs. This study should also examine cost and issues around firing of solid fuels in this scale of equipment and the disposal of wastes, such as spent SO_2 sorbent, from pollution control equipment.

9.0 REFERENCES

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